Analysis of HECO's Proposals for Electricity Restructuring

Produced for the Department of Business, Economic Development, and Tourism by

GDS Associates, Inc.

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I. Introduction

On December 30, 1996, the Hawaii Public Utilities Commission (Commission) initiated Docket 96-0496, initiating an investigation of electricity competition in Hawaii. From May 1997 to July 1998, parties to the docket, which included the four electric utilities, the Consumer Advocate, the Department of Business, Economic Development, and Tourism (DBEDT, the Counties, the U.S. Department of Defense, and other parties met to discuss proposals to restructure and bring more competition to the electric power markets serving Hawaii. At the conclusion of these meetings, the parties filed statements of position with the Commission. Although the Commission has yet to announce further action on the Competition Docket, DBEDT anticipates such action to be forthcoming.

In its statement of position, DBEDT stated its support for introducing competition in generation, energy services, and retail sales of electricity in Hawaii. While noting that additional study was required to confirm the feasibility of competition in Oahu and neighbor islands, DBEDT stressed the importance of competition as a means to reduce Hawaii's electricity costs, which greatly exceed those on the Mainland, where benefits of competition are already being recognized.

DBEDT continues to support the introduction of wholesale and retail competition in Hawaii's electricity markets to the maximum extent that is feasible and consistent with maintaining high service quality and reliability. However, as a preparation for further Commission actions, and to possibly supplement its earlier Statement of Position, DBEDT asked GDS Associates, Inc. (GDS)[1] to conduct further analysis on certain aspects of the HECO Companies' position, including its proposals for:

- Competitive bidding for new generation;

[1] GDS was assisted in the analysis of related legal aspects of these issues by Mr. Jeff Genzer of Duncan, Weinberg, Genzer & Pembroke, P.C.

ENCLOSURE 3

- Performance based ratemaking (PBR); and
- Innovative pricing provisions.

Since one of the principal objectives of increased competition is lower electricity cost, DBEDT is interested in determining the extent to which each of the above issues would serve to meet that objective. In this regard, DBEDT requested that GDS evaluate HECO's proposals and identify any counter proposals or arguments for those elements that do not offer the following:

- A level playing field for new generation, including distributed generation;
- A mechanism to ensure use of renewable energy;
- Reduced electricity costs and rate increases at or below increases in the cost of living; and
- Rates that encourage efficient use of electricity without undue inconvenience to customers.

II. Summary of GDS Recommendations

GDS reviewed HECO's proposals regarding competitive bidding, PBR, and innovative pricing to determine areas where these proposals would not provide benefits of competition and encourage renewable energy and the efficient use of electricity. This analysis was conducted assuming that Hawaii ultimately adopts a competitive model that provides for competitive bidding for all future generation requirements with continued regulation of HECO's power supply function and retail sales of electricity.[2] Our major conclusions and recommendations are:

A. Competitive Bidding

The development of competition in wholesale power markets on the Mainland have transformed competitive bidding for generation services from a relatively lengthy and formal process involving requests for proposals (RFPs), long-term contracts and regulatory oversight, to a more informally administered endeavor involving short to

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[2] Some of the recommendations presented by GDS in this report may conflict with positions expressed by DBEDT in its statement of position. The majority of these conflicts are due to the fact that DBEDT's statement of position supported a full wholesale and retail competition model while the analysis presented herein addresses a wholesale bidding with continued retail regulation of generation model.

medium term power transactions. While these new bidding practices are not fully transferable to Hawaii due to the inherent isolation of its power grid and present lack of a liquid wholesale power market they are useful in certain respects.

Under HECO's proposal, there is no guarantee that competitive bidding will translate into benefits for Hawaii's consumers. For example, under HECO's PBR proposal, to the extent competitive bidding serves to reduce HECO's overall operating costs and increase its earnings, a substantial portion of such benefits would be retained by the Company and its shareholders. Nevertheless, due to the difficulties of implementing full retail competition in Hawaii, mandatory competitive bidding for new generation requirements coupled with continued regulation of generation services represents one of the best near-term options for bringing about economic benefits of increased competition for generation services to Hawaii.

Perhaps the most important common feature of successful bidding programs is the strong discouragement or prohibition of bids by the incumbent utility or its affiliates. This policy increases the effectiveness of the bidding process by eliminating the threat of self-dealing by the utility and simplifying the regulatory oversight of the bidding process. In addition, the elimination of utility or affiliate bids should encourage competitive suppliers to participate in the bidding process and therefore increase the prospects for attractive bids.

The coordination of bidding with the utility's IRP process is another important feature that should be included in Hawaii's bidding program. Through the IRP analysis, HECO's generation requirements and self-build costs for supplying those requirements can be established and used as the avoided cost for judging bids from independent power producers. This information will be useful in designing the RFP and bidding process so that the winning bids serve Hawaii's needs in an efficient and least cost manner. The IRP also provides an analytical framework for evaluating bids against HECO's self-build options in a fair and consistent manner.

A qualifying facility (QF) has a statutorily guaranteed right under the federal Public Utilities Regulatory Practices Act (PURPA) to require a public utility to purchase the QF's capacity and energy. Accordingly, regardless of whether Hawaii introduces a competitive bidding process for new generation, a QF that is either an unsuccessful bidder or chooses not to participate in such process cannot properly be denied its right under PURPA to require a public utility to comply with the statutory purchase obligation. In the event PURPA is repealed, the State needs to reconsider means to encourage the development of efficient cogeneration/combined heat and power technologies.

There is no reason why competitive bidding should jeopardize Hawaii's historical commitment to encourage renewable energy, distributed generation, and combined heat and power technologies.

There are several options to promote these technologies under a competitive bidding model. For administrative efficiency, we recommend that Hawaii simply mandate minimum targets for future development of renewable energy that would be supplied by competitive bidding and take other actions as are necessary to remove disincentives to the development of distributed generation. Net metering should be used to promote customer-owned distributed generation and renewable energy facilities.

Renewable energy portfolio standards (RPS) should be implemented by providing appropriate incentives to HECO, its customers and competitive suppliers to achieve RPS targets directly through the competitive bidding process or other means.[3]

B. Performance Based Ratemaking (PBR)

Based on its review of HECO's initial PBR proposal, DBEDT urged the Commission to proceed with caution in considering PBR, noting that by the Company's own admission, Hawaii's consumers would have paid more under HECO's PBR proposal than they would have paid under the continuation of traditional cost-based ratemaking.

PBR programs have traditionally been allowed only in jurisdictions where full retail competition has been implemented or is planned. In such cases, risks of competition may justify potential rewards of performance improvement under such proposals. HECO's proposal to circumvent cost-based regulations by implementing PBR while at the same time prohibiting retail competition is unjustified and inappropriate.

HECO recently filed its PBR proposal with the Commission. There are a number of significant flaws in this proposal, that serve to effectively shield HECO from any risk and virtually guarantee rewards to the Company based on unjustifiably low performance benchmarks. These flaws further confirm DBEDT's earlier concerns that HECO's PBR program would only serve to increase costs to consumers. The major flaws in the Company's proposal are:

1. The X-factor is too low, which is likely to lead to excessively high prices;
2. The Z-factor is not well defined, and may lead to unjustified price increases;
3. The deadband of the earnings sharing mechanism in which ratepayers share none of the gains is too wide, which will allow HECO's shareholders to keep all or

[3] This approach differs from the full retail competition model under which the RPS is implemented by requiring each power supplier to procure renewable energy as a portion of its overall power portfolio.

most of the increased earnings from cost reductions, increased sales, or any other cause;

4. The 50/50 sharing of earnings above the deadband is inappropriate, and will not encourage HECO to achieve the optimal level of cost reduction; and

5. The combination of the deadband and the 50/50 sharing above the deadband constitutes a highly regressive sharing formula, and is exactly the opposite of the ideal sharing formula, which would award most of the inexpensive and easy gains to ratepayers and most of the expensive and difficult gains to shareholders.

C. Innovative Pricing Proposals

HECO has proposed six types of "innovative pricing" as a means to achieve benefits of competition. Based on our review, some of HECO's pricing proposals generally appear to be reasonable, while others raise certain concerns with regard to their ability to reduce rates for all consumers and encourage the efficient use of electricity. While DBEDT generally supports time-of-use (TOU) rates, HECO's TOU proposal should be carefully evaluated to ensure that low participation and free-ridership concerns that have been experienced with such rates are appropriately addressed. Additionally, HECO's load retention proposal may actually increase prices by forcing HECO to purchase additional generating capacity or by discouraging the construction of efficient new generating capacity from customer self-build options. Under any circumstance, HECO should not be allowed to subsidize rates to some customers by increasing other customers' rates, as would almost certainly occur through its load retention proposal.

III. Analysis of HECO's Competitive Bidding Proposal

In its September 1998, Statement of Position in Docket No. 96-0493, HECO proposed the use of competitive bidding for new generation as an alternative to full retail competition. The Company stated that competitive bidding would provide an efficient and equitable means to encourage competition for new power supplies for Hawaii.

As described in HECO's statement of position, the major components of the Company's bidding proposal include:

1. A Competitive Bidding Process would be used for securing new generation resources using an integrated system approach.

2. Broad eligibility criteria would be applied in qualifying supply-side bidders, and HECO and its affiliates will be allowed to bid.

3. HECO would work with other interested parties to develop procedures to ensure that its competitive bidding program is fair and equitable.

4. If HECO elects to submit a bid, an outside consulting firm would be used to oversee and audit the bid evaluation process.

5. HECO reserves the right to maintain an active role in evaluating proposals. The consulting firm retained to oversee and audit the bid evaluation process would submit a report to the Commission addressing its findings.

6. HECO would propose measures designed to mitigate self-dealing, including: (a) IRP Advisory group input for defining the requirements of bidders, the evaluation and selection process, and development of evaluation criteria, (b) development of a code of conduct and procedures manual, (c) PUC review and pre-approval of the request for proposals (RFP), (d) use of an independent assessor to oversee the evaluation process (if HECO bids) with a report submitted to the Commission, and (e) inclusion of a model Power Purchase Agreement with the RFP.

7. The Competitive Bidding Process would be incorporated with HECO's IRP process.

8. HECO would develop and include in the RFP for power supplies a model power purchase agreement with risk sharing provisions that ensure customers are protected against undue risk.

9. The proposal evaluation process and selection criteria would be designed to ensure viable proposals are selected for the final evaluation, with lowest price being the primary selection criterion.

In its statement of position, DBEDT supported the immediate implementation of competitive bidding for new generation, but expressed concerns that potential benefits of competitive bidding would be jeopardized to the extent HECO was allowed to maintain excessive control of the bidding process. As requested by DBEDT, GDS has re-examined HECO's competitive bidding proposal to identify any modifications that are necessary to ensure that bidding benefits Hawaii's consumers and economy.

A. Industry Status of Competitive Bidding

Competitive bidding for new generation has been required or regularly practiced in Hawaii and most other states for at least the last decade. Competitive bidding programs were initially implemented in the mid-1980's as a means to establish utility avoided costs that serve as the basis for payments to qualified facilities (cogenerators) under the provisions of the Public Utilities Regulatory Policies Act of 1978 (PURPA), 16 U.S.C. Historically, competitive bidding programs have included the following sequence of activities, each of which were subject to some level of regulatory oversight:

1. Future generating capacity and energy requirements are established through an IRP process.

2. The RFP, draft contract, and bidding process are developed.

3. The utility issues the RFP, evaluates bids, and negotiates a power purchase contract.

4. The utility obtains regulatory certification of the power purchase contract.

The traditional bidding process outlined above generally took two to three years from start to finish, depending on the applicable regulations and overall complexity of the process.

However, in the last half of the 1990's, the process of competitive bidding for generation services was significantly transformed. The 1992 Energy Policy Act (EPAct) and the Federal Energy Regulatory Commission's (FERC) Order 888 in 1996 established open transmission access and provisions for exempt (unregulated) wholesale generators on the Mainland. This landmark statute and important ruling stimulated wholesale generation competition and greatly expanded the independent power industry, while promoting the development of competitive wholesale power markets in most regions of the country. As competitive power markets have developed the traditional process whereby regulated incumbent utilities owned and operated all new generating plants has been virtually eliminated.

In this new environment, utilities, power marketers and wholesale consumers are able to procure competitively priced generation services on an hourly, daily or seasonal basis. In addition, in many Mainland markets it is now possible for suppliers and wholesale consumers to hedge long-term risk in market generation prices by purchasing standard market-based electricity futures contracts through the New York Mercantile Exchange (NYMEX).[4] These futures contracts provide for delivery of power in the future at a guaranteed price, thus serving as a means to mitigate price volatility in the short-term market.

These wholesale market developments on the Mainland have transformed competitive bidding for generation services from a relatively lengthy and formal process involving RFPs, long-term contracts and regulatory oversight, to a more informally administered endeavor involving short to medium term power transactions.

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[4] See: http://www.nymex.com/.

Competitive bidding has become a standard practice for utilities to procure competitive generation services and justify those purchases to regulators. However, in many Mainland jurisdictions regulators have relaxed or repealed competitive bidding and integrated resource planning (IRP) requirements in recent years. This move away from mandated bidding can be attributed to the emergence of bidding as a standard practice and to the general decline in regulatory oversight of generation investments as the industry transitions to retail competition and deregulation of generation services.

While the development of competitive wholesale generation markets on the Mainland has changed the nature of competitive bidding, these new bidding practices are not fully transferable to Hawaii due to the inherent isolation of its power grid and present lack of a liquid wholesale power market. With neither wholesale nor retail competition, it is inconceivable that Mainland jurisdictions would have loosened regulatory requirements. Nevertheless, it is useful to examine past and present bidding practices on the Mainland in considering the appropriate bidding model for Hawaii.

B. Competitive Bidding Model for Hawaii

While it is not possible to quantify precisely the economic benefits of competitive bidding, most industry experts agree that properly designed and administered bidding programs can provide at least some of the benefits claimed by HECO, including:

- Increased competition for power generation services;
- A means to place all generation proposals on a level playing field and thus ensure that the best options are selected;
- Increased incentives for new technologies and creative proposals;
- Lower generation prices and provide more choices in generation services; and
- Mitigation of inefficiencies in the existing regulated process of generation planning due to self-dealing.

To date, benefits that have been derived from competitive bidding (i.e., lower generation costs) generally have accrued to retail consumers since generation services are still regulated by most states. However, when generation services are deregulated or alternative ratemaking is allowed, there is no guarantee that economic benefits resulting from competitive bidding will translate into benefits for the ultimate consumer. For example, under HECO's PBR proposal (discussed later in this report), to the extent bidding serves to reduce HECO's overall operating costs and increase its earnings, a substantial portion of such benefits would be retained by the Company and its shareholders.

Nevertheless, due to the difficulties of implementing full retail competition in Hawaii, mandatory competitive bidding for new generation requirements coupled with continued regulation of generation services represents one of the best near-term options for bringing about economic benefits of increased competition for generation services to Hawaii.

Because regulatory-mandated competitive bidding has become a relatively dated issue on the Mainland, there are few recent surveys of bidding activities among the states. In its statement of position, HECO indicates that 28 states have required competitive bidding while another 4 states have implemented bidding on a voluntary basis.[5] In states where competitive bidding was or still is mandated with formal oversight and approval of the state regulatory commission, the results generally have been mixed. This is in part explained by the substantial cost, time and other problems of administering a bidding process that is subject to regulatory hearings and approval. In cases where regulatory oversight is too rigid or public disclosure of bid information is required, prospective bidders may choose not to participate. On the other end of the spectrum, if regulatory oversight is too lax and the utility is allowed to bid on its own requirements or maintain excessive control over the bidding process, bidders may also be discouraged from bidding due to a perceived bias in favor of utility projects. In light of the present lack of competition in Hawaii, it is this latter concern of excess control by the incumbent utility that will very likely discourage bidders.

Several states are generally recognized as having implemented competitive bidding programs that balance the need for regulatory oversight with the demand for flexibility in the bidding process. Among these states are Virginia, Texas, and Georgia. The key features that distinguish the bidding policies implemented by public utility commissions in these states are:

- Bidding by the incumbent utility is discouraged or prohibited.
- Bidding policies are established through informal public utility commission guidelines rather than rigid rules, thus providing the Commission with flexibility to revise the process when needed.
- The utility's generating requirements that are subject to competitive bidding are established through an IRP process that is reviewed and approved by the Commission on a regular cycle.

[5] A December 1996 National Association of Regulatory Utility Commissioners (NARUC) survey reviewed by GDS confirmed this total.

- The proposed bidding and bid evaluation process are reviewed and approved by the Commission prior to issuance of the RFP, but the utility is given appropriate flexibility to alter the bidding process and to negotiate with leading bidders if justified by unforeseen circumstances.

Perhaps the most important common feature of these programs is the strong discouragement or prohibition of bids by the incumbent utility or its affiliates. This policy increases the effectiveness of the bidding process by eliminating the threat of self-dealing by the utility and simplifying the regulatory oversight of the bidding process. When the issue of utility participation is removed from the bidding process, the Company's remaining motivation will be to minimize costs subject to other criteria of the bidding process. In addition, the elimination of utility or affiliate bids should encourage competitive suppliers to participate in the bidding process and therefore increase the prospects for attractive bids.

The ability of the Commission to alter its guidelines regarding the bidding process as circumstances dictate is another important feature that should be included in the design of a bidding program for Hawaii. This is particularly true in light of the concerns that have been raised by HECO and other parties regarding the potential impediments to competition in Hawaii. For example, if experience with the bidding process demonstrates that HECO maintains excessive control over the bidding process, or that there is insufficient competition from independent suppliers to assure that HECO's future generation requirements are served in an economical manner, then the Commission may need to modify its bidding process to address such concerns.

The coordination of bidding with the utility's IRP process is also an important feature that should be included in Hawaii's bidding program. In its statement of position, HECO stated that IRP would no longer be relevant if wholesale competition is mandated in Hawaii.[6] We strongly disagree. Even if HECO is required to purchase its generation requirements from a competitive wholesale market, IRP will remain an essential element of its resource planning and procurement process. Through the IRP analysis, HECO's generation requirements and self-build costs for supplying those requirements can be established. This information will be useful in designing the RFP and bidding process so that the winning bids serve Hawaii's needs in an efficient and least cost manner. The IRP also provides an analytical framework for evaluating bids against HECO's self-build options in a fair and consistent manner.

Furthermore, the IRP process will provide the appropriate forum to review such issues as whether the Company is extending the life of inefficient or otherwise obsolescent

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[6] See page 14 of HECO's Statement of Position in Docket No. 96-0493.

generation facilities as a means to avoid the loss of "market share" to competitive generation suppliers. This can be achieved by requiring that HECO provide detailed unit retirement studies in the IRP process that compare the costs of continuing to operate existing units to recent bid prices for generation.

Finally, Commission oversight of the bidding and bid evaluation process should be maintained to assure that the process is functioning properly to benefit consumers. This review process will provide the appropriate forum for complaints from bidders in the event that HECO abuses the bidding process or if questions arise regarding the bid evaluation results. While it will be necessary for an independent party to conduct the bid evaluation in the event HECO or its affiliates are allowed to submit bids, and generally desirable for an independent evaluation in any case, such independent assessments should be subject to regulatory scrutiny and approval.

C. Impact of Competitive Bidding on Unsolicited Qualifying Facility (QF) Proposals under the Public Utilities Regulatory Practices Act of 1978 (PURPA)

One potential concern raised by HECO's bidding proposal is that it might prevent consideration of new generation projects to the extent they are not submitted in response to a power supply RFP issued by HECO. In particular, such a restriction could potentially be used to limit the development of highly efficient small power production and cogeneration projects that might otherwise provide economic benefits to the State and its citizens, even if the Company does not have an identified need for new capacity.

To address legal aspects of this issue, GDS asked Duncan, Weinberg, Genzer & Pembroke, P.C. (DWG&P) to analyze whether HECO's bidding proposal could be used to circumvent QF provisions of PURPA. The specific question addressed through this legal analysis was whether an entity that met all the necessary requirements to act as a QF under PURPA, but for whatever reason did not participate in HECO's proposed bidding process, could be excluded from consideration as a potential new generation source. As discussed below, DWG&P's legal analysis indicates that an attempt by HECO to use a competitive bidding process to avoid purchases from a QF would violate provisions of PURPA as well as FERC's PURPA implementing regulations.

A. Legal Analysis

The courts and the FERC have interpreted PURPA as essentially providing a QF with a guaranteed market for its power, in the form of the right to require a public utility to purchase capacity and energy from the QF, regardless of whether the public utility in question seeks to make purchases in a regulated or competitive environment. There appears to be no exception to that statutory right applicable to HECO's situation.

Through PURPA, 16 U.S.C. §§796(17)-(18), 824a-3, 824i and 824k, Congress granted qualifying cogeneration and small power production facilities certain benefits, including an exemption from certain regulatory controls. More importantly, under the statute, a QF is assured a market by providing a right to interconnect with the local public utility and to receive rates, as prescribed by FERC, up to the full avoided cost of the utility (Southern Cal. Edison Co. v. FERC, No. 98-1439, 1999 U.S. App. LEXIS 28140 (D.C. Cir. 1999) (emphasis added).

Section 210(a) of PURPA directed FERC to promulgate regulations that "require" electric utilities to offer to:

(1) Sell electric energy to qualifying cogeneration facilities and qualifying small power production facilities, and

(2) Purchase electric energy from such facilities.

1. 16 U.S.C. §824a-3.

In accordance with the statutory directive, FERC's regulations provide that "electric utilities shall purchase electricity made available by [QFs], sell electricity to [QFs] upon request, and . . . make such interconnections with any [QF] as may be necessary to accomplish purchases or sales under this subpart". American Paper Inst. v. American Elec. Power Serv. Corp., 461 U.S. 402, 407 (1983) (emphasis added) (discussing 18 CFR §292.303). See also Western Mass. Elec. Co. v. FERC, 165 F.3d 922, 923 (D.C. Cir. 1999) (an entity's certification as a QF "allows it to compel electric utilities to purchase the power it generates and to require interconnection with those purchasing utilities in order to facilitate such sales") (emphasis added).

Moreover, the obligation to buy power from a QF applies to "any energy and capacity" which a QF makes available either directly to the electric utility or indirectly to the utility through transmission of such energy or capacity by a second utility. 18 CFR §292.303(a). As the FERC has explained, PURPA "impose[s] on electric utilities an obligation to purchase all electric energy and capacity made available from [QFs] with which the electric utility is directly or indirectly interconnected". Public Service Co. of New Hampshire v. New Hampshire Elec. Coop., 83 FERC ¶ 61,224 at 61,199 (1998) (emphasis and internal quotation marks omitted) (PSNH). The FERC added that private parties "cannot lawfully bargain away any portion of the rights QFs enjoy under PURPA . . . or our implementing regulations". Id.

Particularly relevant to HECO's proposal is the following language regarding QFs and competition from the FERC's decision in Utah Power & Light Co., 57 FERC ¶ 61,363 (1991):

> In establishing PURPA . . . Congress did not intend to place qualifying facilities in competition with public utilities. To the contrary, Congress has sought to encourage the development of qualifying facilities by insulating them from competition . . . . In general, qualifying facilities

> produce a component, which is used by public utilities, and consume utility service; but, they are not competitors of public utilities. 57 FERC & 61,363 at 62,190 (emphasis added) (quoting Greensboro Lumber Co. v. Georgia Power Co., 643 F. Supp. 1345, 1373 (N.D. Ga. 1986), aff'd, 844 F.2d 1538 (11th Cir. 1988).

As further indication of the continued validity of a QF's powerful market-access rights, despite the restructuring of and increase in competition in the electric industry in recent years, the FERC noted that "Order No. 888 in no way limits an electric utility's statutory purchase obligations under PURPA". PSNH, 83 FERC at 61,199.

At the same time, the FERC has made clear that QFs, although protected against competition with public utilities, may seek to obtain the benefits of a competitive market. Id. at 62,000-01: "[I]t would be inconsistent with our open access policies to prevent QFs from seeking to participate fully in the competitive market. In this connection, although [the utility] has an obligation to purchase from any QF which can transmit power to it, our rules provide that the parties to QF purchases are free to negotiate purchase rates other than avoided cost. A more competitive environment is expected to foster such outcomes."

Additional evidence of the virtually "air-tight" ability of a QF to require an electric utility to purchase the QF's capacity and energy is found in the QF-related rulemaking proposal III FERC Stat. & Reg. ¶ 32,455 Regulations Governing Bidding Programs (1988). Although FERC subsequently decided not to finalize that proposal, it did so because it determined the rulemaking had been largely rendered moot and overtaken by events, due to actions taken by various state commissions, enactment of the EPAct, and other developments, and apparently not because FERC disavowed its positions and statements in the 1988 proposal.

In the proposal, the Commission requested public comments on allowing state regulatory authorities to implement bidding procedures as a means of establishing rates for power purchases from QFs. Id. at 32,455 and 32,023. FERC viewed the bidding process as a legally and technically viable -- and potentially more accurate -- alternative to what had been up to that point exclusive reliance on administrative determinations of a utility's full avoided costs to establish such rates. Id. at 32,025. In essence, under the proposal, a public utility that is required to purchase capacity and/or energy from a QF could elect to have its avoided cost, and hence the rate it must pay for such purchases, determined through bidders who would compete for the opportunity to supply capacity and energy to the purchasing utility.

Importantly for purposes of HECO's proposal, FERC proposed that although a competitive bid process would be used to establish the purchasing utility's avoided cost, "[u]tilities would still be required to purchase electric energy from QFs that submitted losing bids or decided not to participate in the bidding." Id. (emphasis added). As FERC explained, "[b]idding procedures adopted by states pursuant to PURPA or state law are invalid to the extent the state procedures are inconsistent with PURPA and the Commission's rules and regulations". Id. at 32,027-28. Stated differently, neither FERC nor a state commission can defeat a QF's rights under PURPA to require a public utility to purchase the QF's energy. The bottom line is that "utilities may not shelter capacity from offers by QFs". Id. at 32,028. See also Id. at 32,053 n. 65 ("since not all capacity needs must be subject to bidding, the state regulatory authority can withhold capacity from bidding as long as offers by QFs for such capacity are not precluded") (emphasis added).

However, under the proposal, QFs that were unsuccessful bidders or non-participants in the bidding process would not be entitled to avoided capacity payments; instead, payments to such QFs would be based only on avoided energy costs. Id. at 32,025.

In summary, a QF has a statutorily guaranteed right to require a public utility to purchase the QF's capacity and energy. Absent congressional action to amend PURPA, a QF cannot be denied the opportunity to exercise that right, either by FERC, a state or one or more private entities. Accordingly, regardless of whether Hawaii introduces a competitive bidding process for new generation, a QF that is either an unsuccessful bidder or chooses not to participate in such process cannot properly be denied its right under PURPA to require a public utility to comply with the statutory purchase obligation.

2. Treatment of Renewable Energy and Distributed Generation under Competitive Bidding

One potential concern resulting from the implementation of a competitive bidding process for future generation requirements in Hawaii, is the impact that such a process would have on the development of promising renewable energy and distributed generation technologies. In many cases, the relatively high generation costs associated with renewable energy and distributed generation options could prevent them from competing with conventional generation options unless long term ancillary benefits to the environment and other non-economic factors are appropriately considered. In arguing against the introduction of competition in Hawaii's generation market, HECO cautions that competition could inhibit further development of renewable energy and demand-side management (DSM) programs.[7] HECO's arguments are valid only to the extent that such technologies are required to compete strictly on cost in comparison to other market alternatives. This has not been the case in the past in Hawaii, and there is no reason why the introduction of wholesale competition through competitive bidding should limit the development of these technologies in the future.

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[7] See page 15 of HECO's Statement of Position in Docket No. 96-0493.

Once Hawaii decides that, as a policy matter, it is worthwhile and in the public interest to continue its historical support for the development of renewable energy, distributed generation, and combined heat and power technologies, the key remaining issues that must be decided are what are the appropriate target levels for future development of these resources and what are the most efficient way to accomplish these objectives. The target levels for renewable energy suggested by DBEDT in its statement of position are reasonable.

There are a number options for encouraging the development of these resources. For example, a percentage of generation in each bidding cycle could be designated to be supplied from renewable energy and distributed generation. A similar approach that has been used by several states in the context of a fully deregulated power market is the application of renewable portfolio standards (RPS) that require every power supplier to include a specified percentage of renewable energy in the portfolio of generating resources.[8] The RPS option is appropriate when the market model is full retail competition. However, to the extent Hawaii implements a competition model that calls for mandated competitive bidding for new generation with continued regulatory oversight of the power supply function, a RPS that requires each wholesale supplier to procure renewable energy may not be the most efficient means to encourage renewable resources.

A public benefits fund would provide funding to promote the development of renewable energy and distributed generation technologies. Net metering[9] is another option that has been used in approximately 25 states to promote distributed generation technologies by allowing customers to offset purchases from the utility with energy provided from their distributed generators. These options could be used in conjunction with the RPS/minimum target alternatives to encourage development of renewable energy and distributed generation technologies.

For administrative efficiency, we recommend that Hawaii simply mandate minimum targets for future development of renewable energy that would be supplied by competitive bidding and take other actions as are necessary to remove disincentives to the development of distributed generation. Net metering should be used to promote customer-owned distributed generation and renewable energy facilities. Under the bidding model, an RPS should be implemented by providing appropriate incentives to the utilities, their customers and competitive suppliers to achieve RPS targets directly through the competitive bidding process or other means. Payments for power produced

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[8] See page 42 of DBEDT's Statement of Position in Docket No. 96-0493.

[9] Net metering is an arrangement whereby a utility agrees to accept all excess energy from a customer-owned power project and net that energy against the customer's gross power usage. This results in a credit to the customer based on the full bundled cost of power.

by these resources would be based on competitive bids from like resources, with net metering allowed for customer-owned generation facilities. This direct approach would be a more efficient way to promote and deliver such resources. To the extent adequate competition does not materialize from the competitive bidding for such resources, the Commission should retain the flexibility to require the utilities to continue the efforts it has made in the past to support renewable energy and to similarly support distributed generation options.

IV. Analysis of HECO's Performance Based Ratemaking Proposal

HECO's statement of position included proposals to implement an index-based price cap, earning sharing mechanism, and benchmark incentive plan. Together the Company referred to these proposals as its performance based ratemaking (PBR) plan.[10] Based on its review of HECO's initial PBR proposal, DBEDT urged the Commission to proceed with caution in considering PBR, noting that by the Company's own admission, Hawaii's consumers would have paid more under HECO's PBR proposal than they would have paid under the continuation of traditional cost-based ratemaking.[11]

HECO recently filed an application and testimony with the Commission seeking approval of its PBR proposal. There are a number of significant flaws in this proposal that serve to effectively shield HECO from any risk and virtually guarantee rewards to the Company based on unjustifiably low performance benchmarks. These flaws further confirm DBEDT's earlier concerns that HECO's PBR program would only serve to increase costs to consumers. The following comments address the specific details of HECO's PBR filing.

A. Purpose of Performance-Based Ratemaking

PBR plans should observe a number of basic principles:

A PBR mechanism should protect ratepayer interests and place a downward pressure on rates.

- The plan should provide improved incentives, not rents. The utility should be allowed to increase earnings through improved performance, not have a guarantee of higher earnings through unjustified rewards whether its performance improves or not.

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[10] PBR is a generic industry term for formula-based rates that include benchmark incentives and penalties that are intended to encourage performance improvement by the utility.

[11] See page 56 of DBEDT's Statement of Position in Docket No. 96-0493

- The sharing mechanism acts as a safeguard to ensure that utility profits will be reasonable, emulates a competitive market and insures that ratepayers get a fair share of the rewards of improved productivity.

- Progressive sharing is particularly useful where it is not clear that the benchmarks are too high or too low.

- Monitoring and review of a PBR mechanism must explore the extent to which efficiency has been achieved and the extent to which ratepayers have shared in the benefits of increased efficiency.

- There must be some rational balancing of risks and rewards. To be effective, the Company must accept increases in risk commensurate with the potential increase in earnings (rewards). A greater potential for higher earnings without commensurate increases in risk is little different than simply increasing the utility's allowed rate of return.

HECO's proposed PBR plan falls short of these ideals in many respects. The following narrative discusses problems with HECO's proposals and potential solutions to those problems.

B. HECO's Proposed Price Cap and Earnings Sharing Proposal

HECO proposes that it be allowed to increase rates each year by the Gross Domestic Product Price Index (GDP-PI) minus a 0.76% "X-factor" adjustment for naturally increasing productivity. HECO also proposes that a "Z-factor" be incorporated to adjust for effects of governmental action. Additionally, revenues relating to fuel, purchased energy, integrated resource planning (IRP), and demand-side management (DSM) expenses are not included in the price cap mechanism. If HECO earns greater than 100 basis points above its authorized return on equity, 50% of the excess will be returned to ratepayers via a rate decrease in the following year. Any earnings from DSM shareholder incentives and the proposed service quality mechanism will not be subject to sharing.

This plan shields HECO from risk by allowing a direct pass through of energy and fuel related costs, IRP and DSM expenses, and any cost increases caused by governmental action. Additionally, there will be automatic base rate increases annually due to the GDP-PI indexing and the extremely low X-factor. The proposed service quality incentives are also likely to significantly increase rates. Furthermore, the great majority of excess earnings generated by this plan will accrue to shareholders, with little or none of the excess going to ratepayers. The plan appears to be minimally risky and potentially highly profitable to shareholders, while providing no apparent benefit to ratepayers.

C. The Indexed Price Cap

The concept of indexed price caps is fundamentally flawed. The flaw is that, while prices are adjusted upward automatically to incorporate inflation, prices are not adjusted downward to incorporate increased sales and a declining regulated rate base. Increasing sales and decreasing rate base lead to "automatic" decreases in cost per kWh produced, with little or no effort on the part of the utility. With this bias toward increased prices even in the face of effortlessly declining unit cost, utilities under this type of regulation should be expected to experience windfall profits. This is precisely the reason why utilities propose such schemes, and it is notable that the HECO consultant's report does not mention these factors.

Under indexed price caps, utilities are able to easily increase their profit margins without flowing any of the savings through to ratepayers. The most notable aspect of these plans is the increased profitability of the utility, rather than the speculation that efficiency may increase. Under such a regime, increased efficiency is not necessary for increased profitability to occur. Because unit costs in the electric industry are naturally declining, freezing rates at the current level for five years and allowing the utility to keep all earnings due to cost reductions should be highly profitable. Regulators around the nation have found that rate freezes are generally so profitable to utilities that highly accelerated recovery of potentially stranded costs is usually possible under a rate freeze.

HECO claims that "the inflation measure and the X-factor together are calibrated to track the unit cost trend of the electric utility industry".[12] This does not appear to be the case. Use of the GDP-PI as an index of electricity costs is inappropriate. This index measures changes in the prices of all final goods in the economy. This index is not closely related to the electric utility base rate costs that will be subject to HECO's proposed plan. A producer price index, which measures prices experienced by producers of goods, might seem to be a better index; however, this general index also suffers from a fundamental flaw. The November 1999 Producer price index for all finished goods is 378.9, meaning that the basket of goods used to calculate the index costs 378.9% of what those same goods cost in 1967, the base year of the calculation. The November 1999 PPI for "electric power" index is only 128.9, far lower than the finished goods index. This indicates that the price received by producers of electricity has increased by only 28.9% over the past 32 years, or less than 1% annually. The 278.9% increase in the finished goods PPI since 1967 is approximately ten times as large as the increase in the electricity PPI during that period. The GDP-PI increased at a similarly high rate, in step with overall finished goods prices, and will result in electricity prices rising at a significantly greater rate than actual costs. In fact, it is widely expected that electricity prices will continue to fall on the Mainland, as they have for the past several years. If an index is used, it should be the electric power producer price index.

[12] Application, page 12.

D. The "X-Factor"

HECO's proposed X-factor of 0.76% appears to be a very low standard for productivity improvement, and no evidence is presented supporting use of this number. A 1997 study by National Economic Research Associates (NERA)[13] indicated that total factor productivity of Mainland U.S. electricity distribution companies grew at an average annual rate of 1.86% between 1972 and 1994. Subtracting out the 0.4% TFP growth rate for the U.S. economy as a whole results in an X-factor of approximately 1.5%. Utility TFP growth between 1984 and 1994 was significantly higher, at 2.08% annually. This indicates that not only has average distribution utility efficiency growth been about twice as high as HECO's estimate, but that the rate of efficiency growth has been increasing over time.

E. Estimation of Efficiency and Inflation Indices

This calculation of the X-factor is fundamentally flawed in many respects. The two primary fatal flaws in the calculation are:

- The data series used to calculate the index reach back to 1984, incorporating data that is obsolete and entirely unrelated to current conditions in the electric industry.

- Components of the index are calculated using a simple average of data values rather than trend analysis, the accepted and more accurate method of forecasting.

The 1.18% increase in the GDPPI between 1997 and 1998 was the lowest in the entire series dating back to 1984, and has been steadily decreasing for the past several years. The GDPPI has not been as high as HECO's estimate of 2.67% in many years, and should not be expected to be this high in the future. Once more, use of obsolete data leads to an error in favor of HECO.

The preceding discussion points out how use of a simple arithmetic average leads to highly inappropriate conclusions. No economist would use such a simplistic and clearly inappropriate estimation technique if getting the correct answer was the goal. Averaging a long data series is completely inappropriate if there is a trend in the series, as is clearly the case in most of the data in the consultants' report. The standard method of making projections from this type of data is through regression analysis, which captures the trend in the data and projects that trend forward in time, resulting in a forecast that reflects that trend.

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[13] Makholm, Jeff D. and Michael J. Quinn, "Price Cap Plans for Electricity Distribution Companies Using TFP Analysis", NERA Working Paper, October 21, 1997.

The two charts below demonstrate how trend analysis results in a profoundly different forecast than simple averaging, and how incorporation of obsolete data can bias trend analysis.

Exhibit 1
Annual Growth in U.S. Gross Domestic Product Price Index, 1985-1998, with 5-year Projections Based Upon Linear Regression

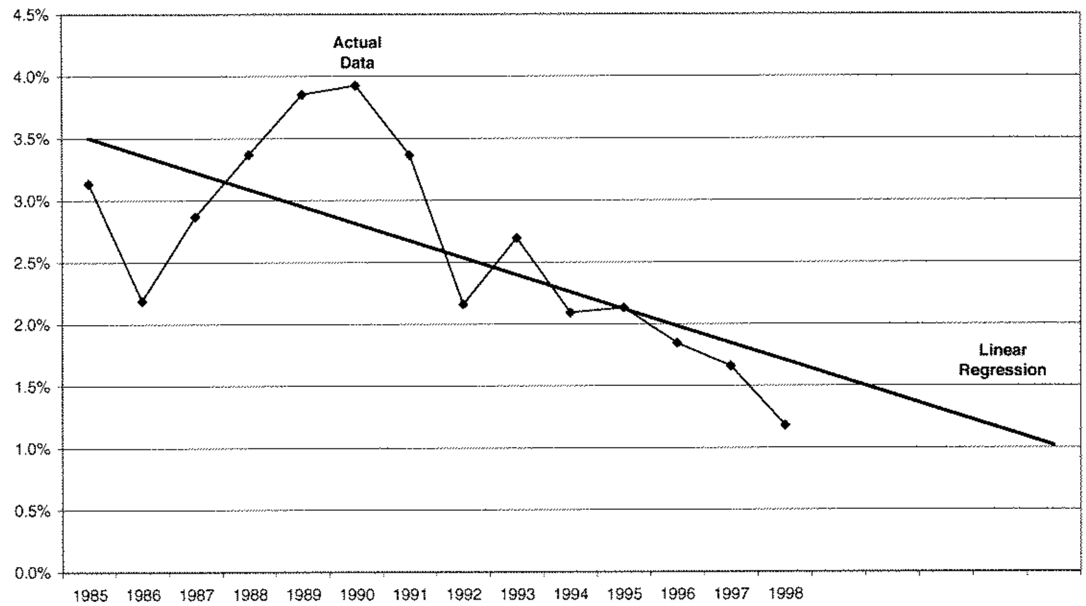
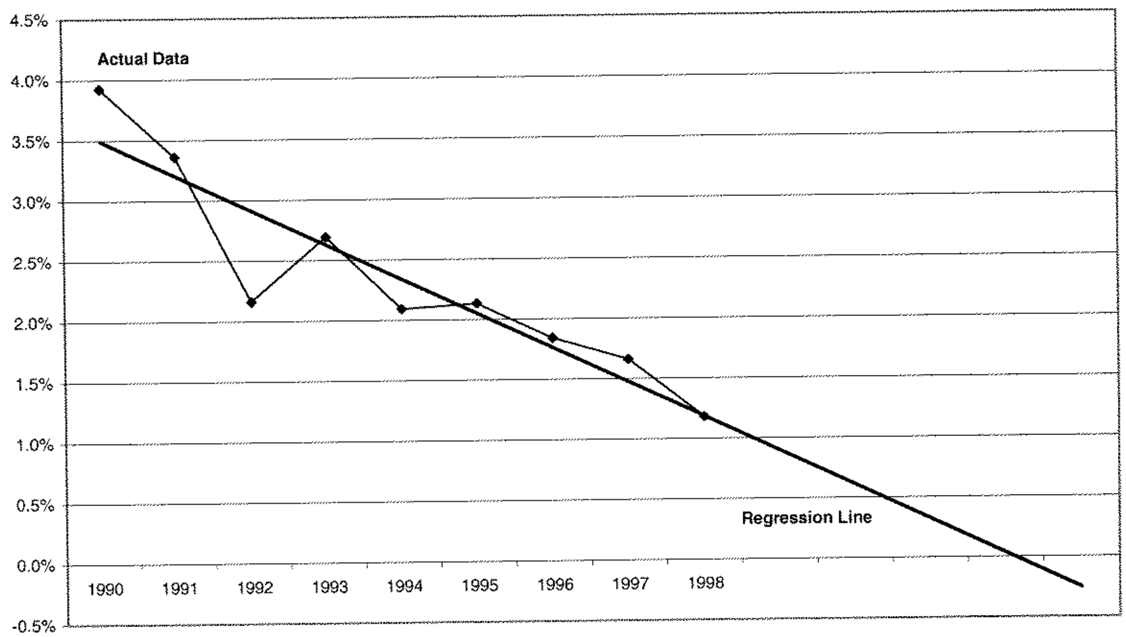


Exhibit 1 illustrates how incorporation of the rising GDP trend of the late 1980s leads to the regression line overestimating actual GDPPI levels over the past several years. The overestimate of the regression analysis, however, is much closer to the actual 1996-1998 GDPPI levels than HECO's extremely inaccurate estimate of 2.47%, which overestimates the 1998 change in the index by more than 109%. (Data Source: HECO-201, page 35 of 36, December 13, 1999).

Exhibit 2 illustrates how excluding the rising GDP trend of the late 1980s leads to a much better fit of the regression line to actual GDPPI levels over the past several years. By excluding the obsolete data that was moving in the opposite direction of the current trend, much more credible forecasting is possible. The trend analysis indicates that if the current trend continues, GDPPI will be less than 1% in 2000, and will continue to decrease thereafter. The regression analysis indicates that GDPPI should be expected to increase by less than 1% annually over the next several years, rather than HECO's highly inflated estimate of 2.47%.

Exhibit 2
Annual Growth in U.S. Gross Domestic Product Price Index, 1990-1998, with 5-year Projection
Based upon Linear Regression



The foregoing analysis illustrates how poor data and poor forecasting technique have resulted in HECO's forecast of GDPPI increase being dramatically inflated compared to that which should reasonably be expected. A similar use of poor data has resulted in HECO's non-energy input price index being extremely inflated.

It is well known that the electricity industry has been a declining-cost industry for a number of years. However, HECO's consultants have chosen to bias all of their calculations by including data dating back to 1984. 1984 is literally ancient history in the electricity industry, and is not relevant for any estimates of future costs. Labor, capital and materials prices were all significantly higher in past years than they are currently. For example, the 1997 price increases in both labor and materials were lower than in any other year in the series. In addition, capital inflation was 0.0% in 1997. It is interesting to note that 1998 data was omitted from this series, even though such data was available several months before the testimony was filed. 1998 continued this trend of increasing efficiency.

In the 1980s and early 1990s, the nation was in the middle of the nuclear building boom that dramatically increased the price of electricity. The index is highly inflated by extremely large increases in capital expenditures in 1989 and 1992. These increases were probably caused by expenses related to some of the nation's most expensive nuclear plants, which came on line during this period. No additional plants of this type or expense are expected to be constructed in this country in the near future, and no such plant has ever been built in Hawaii. In fact, power plants are becoming ever smaller and less expensive. An average of many years of stale historical data that look nothing like anyone's expectations for the future must not be used to determine future rates.

The index is also biased upward by high pre-1995 labor escalation rates. Recent labor escalation rates have been much lower than those in the earlier years of the series, as a result of downsizing, automation, and other productivity increases primarily driven by the prospect of competition. Additionally, materials escalation has been steadily declining since its peak in 1990.[14] The 1997 weighted average of labor, capital and materials escalation rates is 0.61%, dramatically lower than the suggested 3.57%. Due to the fact that the price escalation of all of the input factors has been declining steadily, 0.61% should be the upper limit on the non-energy input price index for U.S. IOU aggregate.

With the above estimates of GDPPI of approximately 1.0% and utility price index of approximately 0.6%, the inflation differential between these numbers is about 0.4%, rather than –0.47%. This differential has profound implications for the level of the X-factor. While HECO claims that inflation in the utility sector has been greater than in the economy as a whole, the opposite is actually true. For this reason, the X-factor must be increased, rather than decreased, by the inflation differential.

An additional problem with HECO's proposed X-factor is that it is based upon long-run growth trends in the investor-owned electric utility industry and the U.S. economy. During the time period under study, utilities have been under exactly the type of regulation that has allegedly led to inefficient operation. Therefore, efficiency improvement under incentive ratemaking should be expected to be significantly greater than historical efficiency growth. NERA's study suffers from this same problem.

Because historical numbers should be expected to underestimate efficiency growth under a PBR scheme, regulators frequently add a "stretch factor" or "consumer dividend" to the X-factor. The consumer dividend has the purpose of sharing expected price cap plan efficiency benefits with customers. A dividend of 0.5% has commonly been featured in telecommunications utility price cap plans.[15]

If the Commission accepts the concept of indexed price caps, a stretch factor of at least 0.5% should be added to the X-factor.

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[14] "Calculation of the base rate input price index for major U.S. IOUs, attached as Table 4 of Exhibit HECO-201 to the HECO, HELCO, MECO Direct Testimonies and Exhibits, December 13, 1999.

[15] Kaufmann, Lawrence and Mark Newton Lowry, "Price Cap Regulation of Power Distribution", Pacific Economics Group.

HECO's TFP differential of 1.61% appears to significantly underestimate recent trends in utility efficiency growth. Over the last five years of the data series, 1993-1997, utility TFP growth averaged 2.77%, while overall U.S. business efficiency has averaged 0.61%, a differential of 2.15%. Negative TFP growth in previous years is clearly not indicative of current trends, and this data should be excluded from the calculation. Further, a lack of clear trends or 1998 data indicates that an average of recent data may be adequate for forecasting purposes. Because the utility non-fuel inflation index has risen approximately 0.4% less than GDPPI in recent years, the X-factor should be 2.15% + 0.4%, or 2.55%, rather than the 0.76% advocated by HECO. Addition of a 0.5% stretch factor brings results in an appropriate X-factor of 3.05%. With expected GDPPI growth of about 1.0%, rates under the indexed price cap should decline by approximately 2.0% annually.

F. The Z-Factor

The "Z-factor" is the equivalent of an absolute guarantee of protection against cost increases for HECO. The Z-factor is not well defined, and would potentially allow HECO to increase its rates under many potential circumstances. HECO could be expected to frequently petition for rate increases in the guise of Z-factor adjustments.

HECO evidently intends that there will be no litigation of any of issues such as X-factor and Z-factor adjustments, meaning little or no opportunity for intervention and discovery by ratepayer groups and other parties. Only HECO has access to the detailed financial information necessary to calculate Z-factors. HECO will certainly file for a Z-factor adjustment only if it leads to a rate increase. Any developments that result in cost savings will not be mentioned by the company, and will likely go undetected. Because HECO's PBR proposal is so biased in the company's favor even in absence of the Z-factor, no Z-factor adjustments should be allowed. If the Commission finds that Z-factor adjustments are acceptable, they should be highly targeted so that they are not subject to gaming or other abuse.

G. The Earnings Sharing Mechanism

The proposal of a 100 basis point deadband in conjunction with the aforementioned biases toward over-earning is equivalent to a proposal that HECO's allowed return be increased by 100 basis points. A deadband around the authorized rate of return assures that the utility will keep the great majority of all over-earnings that do occur. This is the reason that utilities prefer the deadband approach, and usually propose a "symmetric" deadband. This approach is symmetric in appearance only, however. This approach is extremely asymmetric in the risks assumed by ratepayers and shareholders. The shareholders are favored by the automatic price increases under the indexed price cap, increasing sales, declining rate base, and the ability to pursue further cost reductions. However, the ratepayers are penalized by having their rates automatically increased should utility management be so inept that it cannot increase earnings even given all these advantages. In this way, the indexed price cap with an earnings deadband virtually insures windfall profits, and reserves the preponderance of those profits for shareholders, while also insuring that rates increase in each year of the plan. Prices will increase regardless of whether costs increase or decrease. This is a fatal flaw in HECO's proposal.

The deadband approach is more accurately characterized as a "regressive" sharing mechanism, in that the company's share of earnings begins at 100% of any amount above the benchmark return, and then regresses to 50%. A regressive sharing approach is extremely biased in favor of the utility, in that 100% of over-earnings inside the deadband go to the utility, and customers have no opportunity to share in those excess earnings.

For example, San Diego Gas and Electric (SDG&E) was allowed to implement a PBR plan extremely similar to the one currently proposed by HECO. Their plan included 50/50 sharing outside a 150 basis point deadband, and a 300 basis point offramp.[16] The table below illustrates the results of four years of their plan.[17]

Table 1: Sharing of SDG&E's Excess Earnings Between Ratepayers and Shareholders, 1994-97 ($ '000)

Year	Net Operating Income	Rate Base	Excess Earnings Before Sharing	Excess Earnings Before Sharing	Ratepayers Sharing Before Performance Rewards	Shareholder Earnings After Sharing
			Before Tax	After Tax		
1994	$ 291,250	$ 2,863,236	$ 55,366	$ 32,700	$ 1,117	$ 32,042
1995	$ 309,272	$ 2,895,108	$ 45,495	$ 26,709	$ -	$ 26,709
1996	$ 293,807	$ 2,867,983	$ 57,315	$ 33,681	$ 1,358	$ 32,876
1997	$ 294,105	$ 2,796,143	$ 72,199	$ 42,732	$ 4,423	$ 40,124
TOTAL			**$ 230,375**	**$ 135,822**	**$ 6,898**	**$ 131,752**

This table demonstrates that the amount of over-earning accruing to shareholders ranged from a high of 100% in 1995 to a low of 90% in 1997. Over the four-year term, 95% of all excess earnings went to the utility. Likewise, under HECO's proposed regressive sharing, there is little likelihood that customers will ever experience significant benefits.

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[16] G.A. Comnes, S. Stoft, N. Greene, and L.J. Hill. Performance-Based Ratemaking for Electric Utilities. Review of Plans and Analysis of Economic and Resource-Planning Issues, Volume II: Appendices, Lawrence Berkeley Laboratory Energy and Environment Division, November 1995, p. 55.

[17] Summary of UCAN's PBR testimony, 1999.

HECO proposes that it be guaranteed an automatic rate increase if earnings ever fall below 10.5%. Additionally, HECO proposes to share none of its earnings until earnings exceed 12.5%. This proposal is extraordinarily biased against the ratepayers, who assume risk of under-performance, while receiving little of the benefits of HECO's ability to over-earn.

The regressive sharing implemented at SDG&E and proposed for HECO does not provide an incentive for HECO to maximize productivity. If additional earnings due to productivity improvement are small, the Company keeps all the excess earnings and the ratepayers get nothing. However, if the Company aggressively pursues efficiencies and additional savings are large, the ratepayers receive some of the incremental savings. This leaves the Company under-compensated for extraordinary efforts. Thus, under both high and low productivity gain scenarios, earnings are allocated inequitably.

By giving the Company all of the initial, easy savings and only half of the more expensive and difficult savings, the banded ROE plan does not match costs and benefits. This type of plan is referred to as "regressive" because small efficiency gains are highly profitable to the Company, while more significant gains are less profitable. This would give the Company a strong financial incentive to undertake the cheapest and easiest productivity improvements, and a disincentive to invest in more expensive efficiency gains, the benefits of which would have to be shared with ratepayers. This will discourage action up to the most efficient level, where the marginal cost of the action equals the marginal benefit.[18]

The regressive sharing model, in fact, supplies the utility with exactly the wrong incentives. As demonstrated by SDG&E's results, the utility's incentive is to earn up to the level where it no longer keeps 100% of all excess earnings, and then to cease any effort to achieve greater efficiency. This particular sharing structure should be avoided at all costs.

The California Public Utilities Commission (CPUC) has learned this through experience. The CPUC ordered that Southern California Edison (SCE) implement a very different PBR plan beginning on January 1, 1997. This plan called for a much narrower deadband (50 basis points around the benchmark), as well as progressive sharing of earnings outside the deadband. Between 50 and 300 basis points, the shareholder share of gains or losses rises continuously from 25% to 100%. This plan is still very favorable to the shareholders, but gives ratepayers a far better chance of experiencing significant benefits than the plan implemented for SDG&E or the plan proposed by HECO.

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[18] Navarro, Peter. "The Simple Analytics of Performance-Based Ratemaking: A Guide for the PBR Regulator", Yale Journal on Regulation, Volume 13, Number 1, Winter 1996, p. 138.

The SCE plan could be further improved, however. The 50 basis point deadband suffers from the same intrinsic flaw as the wider deadbands, in that it gives all of the most easily achieved over-earnings to the utility, while these are precisely the earnings that should be going back to the ratepayers, as they are more likely the result of naturally occurring cost reductions and sales growth. In an economically rational sharing plan, 100% of all excess earnings should be subject to progressive sharing.

If ratepayers are forced to fund a portion of under-earnings over which HECO has control, HECO's incentive to control these potential losses will be decreased. This is exactly the opposite of an incentive for better performance. If HECO's management performs so poorly that an earnings shortfall is experienced even under the highly favorable conditions of the indexed price cap, management and shareholders rather than ratepayers should be penalized for this poor performance, exactly as would occur in a competitive market.

A "customer sharing" model should be implemented, in which customers get a share of all earnings above the allowed return on equity. Any shortfall should be absorbed by the Company to discourage inefficiency. Table 2 below illustrates an appropriate implementation of this type of earnings sharing plan:

Table 2. A Potential Earnings Sharing Model

Excess Earnings (basis points)	Company's share	Ratepayers' share
Earnings shortfall	100%	0%
Up to 100	25%	75%
101 to 200	50%	50%
201 and greater	75%	25%

This method of sharing would serve to encourage maximum productivity, minimize the probability of windfall profits and make rate reductions more likely than a symmetrical banded return.

H. Service Quality Standards

HECO's proposed service quality standards are based upon the following four performance indicators:

1. System Average Interruption Duration Index (SAIDI);

2. System Average Interruption Frequency Index (SAIFI);

3. Percent of telephone calls to the Customer Assistance Center during regular business hours that are answered within 30 seconds; and

4. Overall satisfaction on a survey of residential customers having recent transactions with HECO.

HECO proposes that the mean values of these indicators over the six-year period 1992-1997 be used as a performance benchmark. No rewards or penalties would be levied within a "symmetric" deadband around the benchmark value.

HECO's proposed deadband approach is once again problematic. This approach does not give HECO an incentive to improve or even maintain quality. The averaging of high and low performance years is adequate to ensure that the standard is lower than performance that HECO has already attained in the past. There should not be any deadband that allows for significantly lower performance than this already low standard before a penalty is levied. Penalties should be levied for any performance below historical levels. A penalty for any under-performance will encourage HECO to improve service quality.

High quality service should be taken for granted. If service quality is not adequate, improvement should be mandatory. It is unreasonable for a utility to say that it will only provide high quality service if it is subsidized. Consumers are price sensitive. They want adequate service at the lowest price, and generally have no desire to pay the extra cost required to increase quality above required levels.[19] They do not want expensive, gold plated service that is perhaps slightly better than the already high level of service they have come to take for granted. It is not appropriate to use rewards as an incentive for utilities to adequately provide necessary regulated utility services, as required by law. All of the performance rewards are completely unjustified, and are likely to be injurious to customers.

1. SAIDI/SAIFI Performance Indices

HECO's proposed rewards and penalties are not based on any estimate of the cost for the Company to reduce outages. HECO's proposed rewards and penalties are instead based upon highly speculative estimates of the value of not being interrupted. The proposed rewards and penalties appear to be exorbitantly large, and are not cost-based. If the rewards are significantly greater than the cost to achieve those rewards, HECO will have a great incentive to invest very heavily in its distribution system, for which it will be handsomely rewarded. This means that the cost of the system improvements may be greater than the benefits derived from those investments. However, HECO will find the investments very profitable even if they are uneconomic because of the large, non-cost-based rewards it will receive under its proposal. Additionally, any capital expenditures

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[19] Biewald, Bruce, Tim Woolf, Peter Bradford, Paul Chernick, Susan Geller and Jerrold Oppheim. "Performance-Based Regulation in a Restructured Electric Industry", Prepared for the National Association of Regulatory Utility Commissioners, November 8, 1997, page 48.

will be incorporated into the regulated rate base at the termination of the rate freeze, leading to a rate increase. After the new rates are set, customers will be paying again for the excessive investment that they have already unwillingly paid for once through the proposed reward system. The proposed rewards appear to be a device to force ratepayers to pay twice for HECO's investments.

2. Telephone Response

HECO proposes that if greater than 60.6 percent of calls are answered within 30 seconds, the company should be granted a performance reward. This means that HECO will receive rewards even if nearly 4 out of every 10 calls are never answered at all. This is a highly inadequate standard. A better standard would be similar to that implemented at Southern California Gas Company. At SoCalGas, 80% of all calls must be answered within 60 seconds and 90% of emergency calls must be answered within 20 seconds, or a penalty is imposed. The penalty is $20,000 for each tenth of a percent (0.1%) the performance is below each standard, with no deadband, and no maximum penalty. The standard appropriately does not include any rewards.[20]

There is a pitfall in imposing this type of penalty, however. If the company is penalized for not answering calls, there will be an incentive to maximize the number of calls that receive a busy signal. An objective of a minimum number of busies, such as 3%, should be imposed. Busies on emergency calls should be less than the overall standard.

The monthly level of abandoned calls in the call center and any of its contractors should be monitored and reported on a quarterly basis to the PUC. Abandoned calls should include all calls regardless of time before the customer abandons. A standard of no more than 5% abandoned should be implemented.

3. Customer Satisfaction Surveys

HECO has proposed that surveys of customer satisfaction should be used to determine rewards and penalties for service quality. However, survey questions measure the service the customer perceives, not what is actually happening. Surveys of the satisfaction level of customers are highly subjective and are likely to be a faulty indicator of service quality. For example, SDG&E experienced little movement in its satisfaction indicator for the telephone segment in mid 1997, despite a major increase in busies and abandoned

[20] Prepared Testimony of Gayatri M. Schilberg, JBS Energy, Inc. on behalf of Utility Consumers Action Network, California Public Utilities Commission App. 98-01-014, Performance Based Ratemaking of San Diego Gas & Electric Company, July 3, 1999.

calls, as well as a significant decline in the percentage of calls answered in 60 seconds.[21] This is typical of an index that measures perception rather than reality.

Satisfaction surveys in general should be viewed with a great deal of suspicion. The manner in which questions are phrased and the order in which questions are asked may both bias survey responses. Additionally, excluding certain types of customers from surveys can increase reported satisfaction levels. Marketing activities can also bias survey results. If rewards or penalties are based upon customer perceptions, utilities are encouraged to engage in advertising campaigns for the purpose of simply improving the public's perception of the company, rather than spending the money on actual service improvements. For this reason, only actual measured performance should be used to judge the adequacy of a utility's service quality. As an example of how lower performance may not translate into lower survey results, SDG&E's 1997 telephone center satisfaction survey results are compared to actual performance are illustrated in Table 3 below.

Table 3: SDG&E Telephone Center Performance, 1997

Criteria	Q1	Q2	Q3	Q4
% Very Satisfied	93.8	92.4	93.6	93.8
% Total Calls Answered in 60 sec.	56.6	37.7	37.1	483.5
Busies as % of Total Calls	3.3	6.6	8.9	5.4
Abandoned as % of Total Calls	4.1	6.1	6.0	4.5

Sources: SDG&E's Compliance with D.94-08-023, May 15, 1998, p. 19; and calculations from UCAN DR 1 Q 39 (Attachment 24) as percent of total calls, e.g. calls answered plus abandoned and busies.

As demonstrated above, it is possible for a significant increase in busies, abandoned calls and calls not answered within 60 seconds to occur without any material reduction in the satisfaction index. SDG&E's Customer Service Monitoring System overall indicator still earned the maximum reward in 1996 despite a satisfaction decline in five of the seven segments in the last quarter of 1996, including a very large 4-point decline in call center satisfaction.[22] Instead of surveys not backed by any real indication of whether HECO is actually performing up to standard, targeted standards based upon actual performance should be implemented.

Southern California Edison voluntarily initiated on its own a program in which it gives $50 to customers when it cannot meet 1) its commitment for service initiation, 2) a 4-hour response time to service disruption in non-storm conditions, and 3) a 24-hour

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[21] Schilberg, 1999.

[22] SDG&E Compliance with D.94-08-023, PBR, Final Performance Report for 1996, May 15, 1997.

restoration time in non-emergency conditions.[23] This is the type of service quality standard that HECO should be instituting. The manner in which inadequate service quality should be addressed is through direct compensation to specific customers that have been inconvenienced.

V. Analysis of HECO's Innovative Pricing Proposals

HECO proposes six types of "innovative pricing" as a means to achieve benefits of competition: (1) rate restructuring, (2) time-of-use rates, (3) customer migration rates, (4) flexible pricing, (5) new service options, and (6) two-part rates. GDS reviewed these proposals in an effort to identify any rates that would not tend to result in reduced electricity costs or that could encourage inefficient use of electricity. Some of HECO's pricing proposals generally appear to be reasonable. The specific proposals that raise concerns are discussed below.

A. Residential Time of Use Rates

In its statement of position, DBEDT outlined its general support of the use of time of use rates. Residential time of use rates are conceptually a good idea, but when improperly designed, such rates may not accomplish the desired goals of increased energy efficiency and reduced costs for ratepayers. The potential problems with TOU rates are that to encourage customer participation, utilities often have to guarantee customers that their rates will not increase under the TOU rate structure. Additionally, self-selection of participants can sometime result in all or most TOU customers being "free-riders"[24], with little resultant benefit in overall energy efficiency. Though low participation and free-ridership concerns can be addressed in the design of the TOU rates, HECO's proposed requirement that customers purchase a TOU meter virtually guarantees that there will be no participation in the program. DBEDT should continue to support the implementation of TOU rates, with due consideration given to these potential concerns.

B. Load Retention Rates

Discounted rates may be useful in retaining customers that might uneconomically bypass the utility system. However, load retention is not necessarily a good thing for the utility system or its customers. If a capacity shortage exists, load retention may actually increase prices by forcing HECO to purchase additional generating capacity. If demand

[23] Schilberg, 1999.

[24] A free-rider is a customer whose current consumption pattern will result in lower electricity bills under the TOU rate, and therefore no behavioral change is needed in order to benefit from the rate.

is growing and no excess capacity exists, discounted rates that discourage voluntary construction of efficient new generating capacity may be economically destructive. This is especially true if the consumer-built option has a higher efficiency than the utility-built alternative, as is usually the case.

Under any circumstance, HECO should not be allowed to subsidize rates to some customers by increasing other customers' rates. Shareholder funding of rate discounts is commonly allowed. If HECO actually has excess capacity, some shareholder-funded rate discounting could be beneficial, but even shareholder-funded load retention is inappropriate when this would cause additional capacity investment to serve the retained load.

HECO has used a number of faulty assumptions in its analysis of the rate impact of allowing customers to install cogeneration systems. These include an excessively high load factor, an assumption that 100% of the customer's load will be served by the cogeneration system, and that the customer will purchase no energy or even standby service from HECO. These are all highly unreasonable assumptions, and their analysis is not useful for decision making purposes.

C. Schedule H - Commercial Cooking, Heating, and Cooling Service

Elimination of the demand charge in conjunction with a declining-block rate will encourage greater peak-period consumption, increasing capacity needs and total system operating cost, as the highest-cost generators operate during the peak period. This is likely to result in other rate classes subsidizing this class. The modifications to this rate do not appear economically rational or justifiable. If a demand charge was appropriate when this rate was designed, it is appropriate to inquire why elimination of the demand charge is being proposed at this time.

D. Schedule F2 - Utility-Owned Public Street and Highway Lighting Facilities

Under this rate schedule, HECO will install, own, operate and maintain the street and highway lighting. Operation and maintenance of street lighting appears to be at least potentially a competitively provided service, rather than a natural monopoly service. For example, an aggregator in Massachusetts has issued a nationwide request for proposals seeking bidders to operate and maintain streetlights for communities across that state.[25] As such, HECO should allow customers to procure maintenance service from a competitive third-party provider at the customer's option. If customers are locked into a

[25] "Aggregator issues RFP to operate Mass. municipal streetlight systems", Electric Utility Week, December 13, 1999, page 12.

maintenance contract with HECO, competitive providers will have no chance to break into this market.